Revised Preliminary Determination of Compliance

High Desert Power Project
Victorville, California

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List of Abbreviations

ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
CEC	California Energy Commission
CO	Carbon Monoxide
CTG	Combustion Turbine Generator
HDPP	High Desert Power Project
HRA	Health Risk Assessment
HRSG	Heat Recovery Steam Generator
LAER	Lowest Achievable Emission Rate
MDAQMD	Mojave Desert Air Quality Management District
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
O_2	Molecular Oxygen
PM_{10}	Fine Particulate, Respirable Fraction
PSD	Prevention of Significant Deterioration
SCIA	Southern California International Airport
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_x	Oxides of Sulfur
STG	Steam Turbine Generator
TOG	Total Organic Gases
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

1. Introduction

The Mojave Desert Air Quality Management District (MDAQMD) received an Application for New Source Review for the High Desert Power Project (HDPP) from the HDPP, LLC (Constellation Power/Inland Energy) dated October 10, 1997. The HDPP application detailed three possible final configurations for the project, with the understanding that the proponent will select one configuration prior to the commencement of construction. The MDAQMD notified the applicant that this application was complete with a letter dated November 19, 1997.

The MDAQMD issued a Preliminary Determination of Compliance (PDOC) for the HDPP on May 14, 1998. Significant comments were received regarding the PDOC, and HDPP, LLC has made substantial changes to the proposed project. As a result, the MDAQMD is now issuing a revised PDOC for the HDPP.

As required by MDAQMD Rule 1306(E)(1)(a), this document will review each HDPP configuration, evaluating worst-case or maximum air quality impacts, and establishing control technology requirements and related air quality permit conditions for each configuration. This document represents the preliminary pre-construction compliance review of the proposed project, to determine whether construction and operation of the proposed project will comply with all applicable MDAQMD rules and regulations.

2. Project Location

The HDPP will be located on a 25 acre site on the Southern California International Airport (SCIA), formerly known as George Air Force Base. SCIA is located in the northwest corner of the City of Victorville. The HDPP will be built on Parcel No. 0468231-01, a portion of Parcel 1 of section 24, at Township 6 North, Range 5 West (San Bernardino Base and Meridian) in the County of San Bernardino, California.

Site Description

The HDPP site under each configuration will include combustion turbine trains with exhaust stacks, heat recovery steam generator units, steam turbine generator units, cooling towers, water treatment, transformers, and a 230kV high voltage switchyard.

A combined control room and administrative building and a combined warehouse/shop building will be located on the project site. An above-ground rack system will support piping, cable, and wiring. A microwave tower at the project site will provide off-site communication. Perimeter and internal paved roads within the plant will provide vehicle and maintenance equipment access. Natural gas will be delivered to the plant site boundary by a new 24-inch line approximately 2.75 miles long which will be constructed by Southwest Gas Corporation. Additional natural gas may be obtained form PG&E and/or Kern River pipelines near California Highway 58.

3. Description of Project

The HDPP proposes to construct an electrical generating facility employing natural gas-fueled combined-cycle gas combustion turbines as its primary generating units. The HDPP is intended to sell electricity via bilateral power sales agreements to the regional power pool and other consumers. Commercial operation is scheduled to commence in 2001. Due to the uncertainties introduced by deregulation of the utility industry, HDPP is considering two plant configurations. The specific configuration will not be selected until there is greater certainty of the actual market need.

4. Project Configurations

The two proposed plant configurations involve variations in the number and class of turbines. The two conceptual designs are as follows.

- Three F class CTGs operating in combined cycle mode (the 3F Combined)
- Two G-class CTGs operating in combined cycle mode (the 2G Combined)

For both configurations, the CTGs will be exclusively fueled by pipeline-quality natural gas, without back-up liquid fuel firing capability.

Since HDPP has not made the final turbine vendor selection at this time, the parameters used herein for purposes of evaluation can be considered to define an operating envelope for each configuration. Only equipment which can operate within the operating envelope (and permit conditions) for the configuration selected for construction will be permitted. Vendors and equipment currently under consideration include, but are not limited to: General Electric Frame 7FA, Westinghouse 501F and Westinghouse 501G.

Each configuration employs CTGs as the primary heat source. The CTG power blocks each include a turbine air compressor section, gas combustion system combustors, power turbine, and a 60-hertz generator. Ambient air is filtered and compressed in a multiple-stage axial flow compressor. Compressed air and natural gas are mixed and combusted in the turbine combustion chamber. Lean pre-mix low NO_x combustors are used to minimize NO_x formation during combustion. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine which drives both the air compressor and the electric power generator. Heat from the exhaust gas is then recovered in a heat recovery steam generator (HRSG) which feeds a steam condensing turbine (STG) driving an electric generator. Supplemental heat will be provided to the HRSG by duct burners under some circumstances.

Project Configuration #1 – Combined Cycle (Three F Class)

This project configuration will employ three F-class CTGs operating in combined (or combined Brayton and Rankine) cycle mode (with auxiliary systems). Each CTG will exhaust into a Heat Recovery Steam Generator (HRSG). The steam generated will drive a condensing Steam Turbine Generator (STG). Each condensing STG will be cooled by a cooling tower. This configuration

will produce approximately 750 MW at 59°F ambient. This project configuration will have an expected availability of 95 percent and operate up to 8,760 hours each year.

Each HRSG is a horizontal, natural circulation type unit with three pressure levels of steam generation, a reheat loop and an integral de-aerator. A duct burner in each HRSG will provide supplementary firing during high ambient temperatures to maintain constant steam production to the STG. A Selective Catalytic Reduction (SCR) system and high-temperature oxidation catalyst will be located within each HRSG. High and low pressure steam will be produced in each HRSG and flow to a STG. Each STG will drive an electric generator to produce electricity. STG exhaust steam will be condensed in a surface condenser with water from a dedicated multi-cell wet cooling tower.

This 3F Combined configuration consists of equipment having the following 15 application numbers:

- 98001134 Combustion Turbine 3F-1
- 98001135 Duct Burner 3F-1
- 98001136 SCR Unit 3F-1
- 99003920 Oxidation Catalyst 3F-1
- 98001137 Cooling Tower 3F-1
- 98001138 Combustion Turbine 3F-2
- 98001139 Duct Burner 3F-2
- 98001140 SCR Unit 3F-2
- 99003921 Oxidation Catalyst 3F-2
- 98001141 Cooling Tower 3F-2
- 98001142 Combustion Turbine 3F-3
- 98001143 Duct Burner 3F-3
- 98001144 SCR Unit 3F-3
- 99003922 Oxidation Catalyst 3F-3
- 98001145 Cooling Tower 3F-3

Project Configuration #2 – Combined Cycle (Two G Class)

This project configuration will employ two G-class CTGs operating in combined (or combined Brayton and Rankine) cycle mode (with auxiliary systems). Each CTG will exhaust into an HRSG. The steam generated will drive a condensing STG. Each condensing STG will be cooled by a cooling tower. This configuration will produce approximately 700 MW at 59°F ambient. This project configuration will have an expected availability of 95 percent and operate up to 8,760 hours each year.

Each HRSG is a horizontal, natural circulation type unit with three pressure levels of steam generation, a reheat loop and an integral de-aerator. A duct burner in each HRSG will provide supplementary firing during high ambient temperatures to maintain constant steam production to the STG. An SCR system and high-temperature oxidation catalyst will be located within each

HRSG. High and low pressure steam will be produced in each HRSG and flow to a STG. Each STG will drive an electric generator to produce electricity. STG exhaust steam will be condensed in a surface condenser with water from a dedicated multi-cell wet cooling tower.

This 2G Combined configuration consists of equipment having the following ten application numbers:

- 98001146 Combustion Turbine 2G-1
- 98001147 Duct Burner 2G-1
- 98001148 SCR Unit 2G-1
- 99003923 Oxidation Catalyst 2G-1
- 98001149 Cooling Tower 2G-1
- 98001150 Combustion Turbine 2G-2
- 98001151 Duct Burner 2G-2
- 98001152 SCR Unit 2G-2
- 99003924 Oxidation Catalyst 2G-2
- 98001153 Cooling Tower 2G-2

Overall Project Emissions

In summary, the HDPP configurations differ in terms of the number and type of primary generating units, employed in a common combined cycle natural gas-fired turbine generation scheme. These differences result in somewhat different maximum annual criteria emissions. All configurations will produce exhaust emissions during three performance modes: startup; operations mode at full load; and shutdown. Both configurations feature the operation of a wet cooling tower with associated entrained particulate emissions.

Annual Emissions Summary

The following represents maximum annual operational emissions for each configuration. The maximum cooling tower PM_{10} emissions are included.

HDPP Maximum Annual Operational Emissions (tons per year)					
	NO_x	**CO**	**VOC**	**SO_x**	**PM_{10}**
3F Combined	205	914	144	13	155
2G Combined	189	631	103	13	104

Equivalent Hourly Emission Rates

Maximum hourly emission rates can be calculated for each configuration in operational mode. Each cooling tower will emit a maximum of 1.1 pounds of PM_{10} per hour in the 3F Combined configuration and 1.5 pounds of PM_{10} per hour in the 2G Combined configuration.

HDPP Operational Mode Hourly Emission Rates (per turbine) All values in pounds per hour					
Configuration	NO_x	CO	VOC	SO_x	PM_{10}
3F Combined	18.00	35.06	4.41	1.11	12.90
2G Combined	24.55	47.82	6.40	1.51	13.10

5. Control Technology Evaluation

Best Available Control Technology (BACT) is required for any new facility that emits, or has the potential to emit, 25 pounds per day or more or 25 tons per year or more of any non-attainment pollutant or its precursors (MDAQMD Rule 1303(A)). Based on the proposed project's maximum emissions as calculated in §4 above, each permit unit at the proposed HDPP must be equipped with BACT for NO_x, VOC, CO, PM_{10} and SO_x. The applicant has submitted a BACT analysis[1] which evaluates the available control technologies for these pollutants, trace organics, and trace metals for each configuration. The applicant subsequently submitted a supplemental BACT analysis to address the revised project.[2] These BACT analyses also include a listing of previous BACT/Lowest Achievable Emission Rate (LAER) determinations for gas turbines from USEPA's BACT/LAER Clearinghouse.

NO_x BACT

NO_x is a precursor of ozone and PM_{10}, and both ozone and PM_{10} are non-attainment pollutants at the proposed facility location. NO_x will be formed by the oxidation of atmospheric nitrogen during combustion within the gas turbine generating systems.

The MDAQMD has reviewed recent gas turbine NO_x BACT determinations, including recommendations by USEPA and CARB. On June 12, 1998 the SCAQMD recognized a BACT guideline value of 2.5 ppm NO_x (corrected to 15% O_2 with no averaging time specified) for natural gas-fired turbines. USEPA has identified an "achieved in practice" BACT value of 2.0 ppmv over a three-hour rolling average based on the recent performance of a Vernon, California natural gas-fired 32 megawatt combined cycle turbine (without duct burners) equipped with the patented SCONOX system. Brooklyn Navy Yard Cogeneration Partners represents the most stringent gas turbine NO_x limit in the BACT/LAER clearinghouse at 3.5 ppm (corrected to 15% O_2) and averaged over one hour. The HDPP proposes 2.5 ppmvd (corrected to 15% O_2) over a three hour averaging time with an ammonia slip of 10 ppmvd (corrected to 15% O_2) as a NO_x BACT emission limit.

ABB was announced on September 10, 1998 as the exclusive licensee for SCONOX for United States turbine applications >100 megawatts, and ABB has stated that scale up and engineering work will be required before SCONOX can be offered with commercial guarantees for large

[1] "High Desert Power Project Control Technologies Evaluation," ENSR Corp., ENSR Doc. No. 8700-835-400-BACT, January 1998.
[2] High Desert Power Project Emissions and BACT Addendum," ENSR Corp., ENSR Doc. No. 8700-835-400R2, October 1998.

turbines.[3] As a result, MDAQMD does not consider the SCONOX system (and the 2.0 ppmvd limit) to have been demonstrated in practice or achievable for >100 megawatt gas turbines.

Therefore the District has determined that a maximum NO_x concentration of 2.5 ppmvd (corrected to 15% O_2) averaged over three hours, with an ammonia slip of 10 ppmvd (corrected to 15% O_2) averaged over three hours is acceptable as NO_x BACT for the combined cycle, duct burner equipped, natural gas-fired >100 megawatt gas turbines.

CO BACT

Carbon monoxide is formed as a result of incomplete combustion of fuel within the gas turbine generating systems. CO is an attainment pollutant at the proposed facility location.

The MDAQMD has reviewed recent gas turbine CO BACT determinations, including recommendations by USEPA and CARB. On June 12, 1998 the SCAQMD recognized a BACT guideline value of 10 ppmvd CO (corrected to 15% O_2 with no averaging time specified) for natural gas-fired turbines. Newark Bay Cogeneration Partners represents the most stringent gas turbine CO limit in the BACT/LAER clearinghouse at 1.8 ppmvd. The HDPP proposes 8 ppmvd (corrected to 15% O_2) over a three hour averaging time as a CO BACT emission limit with a high temperature oxidation catalyst (the oxidation catalyst will be optimized for VOC oxidation). CARB has provided source test data for gas turbines that suggests that the oxidation catalyst proposed by HDPP will result in CO concentrations considerably lower than 8 ppmvd. MDAQMD will review operational data to assess whether a lower CO limit is more appropriate after project startup.

Therefore the District has determined that a maximum CO concentration of 8 ppmvd (corrected to 15% O_2) averaged over three hours is acceptable as CO BACT for the combined cycle, duct burner equipped, natural gas-fired >100 megawatt gas turbines (with the possibility of a lower limit in the future based on operational data).

PM_{10} BACT

PM_{10} is a non-attainment pollutant at the proposed facility location. Particulate will be emitted by the gas turbine generating systems due to fuel sulfur, inert trace contaminants, mercaptans in the fuel, dust drawn in from the ambient air and particulate of carbon, metals worn from the equipment while in operation, and hydrocarbons resulting from incomplete combustion. Particulate will also be emitted by the cooling towers through particulate mist entrainment.

Gas Turbines

There have not been any add-on control systems developed for gas turbines from the promulgation of the first New Source Performance Standard for Stationary Turbines (40 CFR 60 Subpart GG, commencing with §60.330) in 1979 to the present. The cost of installing such a

[3] Letter from Kreminski/Broemmelsiek (ABB Power Generation) to the Massachusetts Department of Environmental Protection dated November 4, 1998.

device has been and continues to be prohibitive and performance standards for particulate control of stationary gas turbines have not been proposed or promulgated by EPA.

The most stringent particulate control method for gas turbines is the use of low ash fuels such as natural gas. No add-on control technologies are listed in the EPA BACT/LAER Clearinghouse listing provided by the applicant, and only 37 of the 80 turbine listings have PM limits. Combustion control and the use of low or zero ash fuel (such as natural gas) is the predominant control method listed for turbines with PM limits.

The District determines that the sole use of natural gas fuel is acceptable as PM_{10} BACT for the combined cycle, duct burner equipped, natural gas-fired >100 megawatt gas turbines.

Cooling Towers

Cooling towers will be equipped with mist eliminators guaranteed by the manufacturer to limit drift to 0.001 percent. The applicant proposes a total dissolved solid limit of 4,000 milligrams per liter, a maximum water use of 90.351 billion gallons per year per tower (based on a recirculation rate of 57,300 gallons per minute (gpm) per cooling tower on an annual basis) in the 3F configuration and a maximum water use of 77.305 billion gallons per year per tower (based on a recirculation rate of 73,540 gpm per cooling tower on an annual basis) in the 2G configuration.

The District determines that these parameters are acceptable as PM_{10} BACT for this project's cooling towers.

SO_x BACT

SO_x is a precursor to PM_{10}, a non-attainment pollutant at the proposed facility location. SO_x is exclusively formed through the oxidation of sulfur present in the fuel.

The emission rate is a function of the efficiency of the source and the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_x. The gas turbines will be fired exclusively with natural gas which typically contains an average of 30 ppm by weight of sulfur.

The District determines that the exclusive use of natural gas fuel is acceptable as SO_x BACT for the combined cycle, duct burner equipped, natural gas-fired >100 megawatt gas turbines.

VOC and Trace Organic BACT

VOC is a precursor for ozone and PM_{10}, which are non-attainment pollutants at the proposed facility location. VOCs and trace organics are emitted from natural gas-fired turbines as a result of incomplete combustion of fuel and trace organics contained in pipeline-quality natural gas.

The most stringent VOC control level for gas turbines has been achieved by those which employ catalytic oxidation for CO control. An oxidation catalyst designed to control CO would provide a side benefit of controlling in the range of VOC emissions. The HDPP has proposed a high temperature oxidation catalyst achieving approximately 40% destruction of non-methane, non-

ethane organic hydrocarbons as VOC BACT. CARB has provided source test data for gas turbines that suggests that the oxidation catalyst proposed by HDPP will result in VOC concentrations on the order of 1 ppmvd.

The District has determined that a high temperature oxidation catalyst achieving approximately 40% destruction of non-methane, non-ethane organic hydrocarbons shall represent VOC and trace organic BACT for the combined cycle, duct burner equipped, natural gas-fired >100 megawatt gas turbines.

6. Class I Area Visibility Protection

ENSR Corporation evaluated the visibility reduction potential of the HDPP on Prevention of Significant Deterioration (PSD) Class I areas,[4] supplemented by data provided by the applicant on June 19, 1998. The MDAQMD approves of the analysis methods used in the visibility analysis and the findings of the visibility analysis.

Findings

The HDPP was estimated to generate a maximum 24-hour reduction in visibility of 0.56 deciviews, which is less than the significant change level of 1.50 deciviews. The HDPP plume was estimated to produce maximum ΔE of 1.62 at any location and 0.522 inside a PSD Class I area (the screening criteria for ΔE is 2.00), and contrast of 0.011 at any location and 0.000 inside a PSD Class I area (the screening criteria is 0.050 for contrast).

Inputs and Methods

Visibility impacts were evaluated for each wilderness area within 100 km of the proposed HDPP site: Cucamonga Wilderness Area (41 km), San Gabriel Wilderness Area (52 km) and San Gorgonio Wilderness Area (62 km). In addition, visibility impacts were evaluated for the Joshua Tree National Monument, 101 km from the proposed site. George AFB meteorological data for 1987 through 1991 was used for each analysis. Worst-case one hour emissions were used for each analysis. Plume blight was evaluated using the USEPA screening model (VISCREEN, USEPA 1988). Regional haze was evaluated using the USEPA approved regional haze visibility screening analysis guidance (*Interagency Working Group on Air Quality Modeling Phase I Report*, USEPA 1993).

7. Air Quality Impact Analysis

HDPP performed the National Ambient Air Quality Standard (NAAQS) and Prevention of Significant Deterioration impact analyses for CO, PM_{10}, SO_2[5] and NO_2[6] emissions. These analyses

[4] "High Desert Power Project Visibility Analysis," ENSR Corp., ENSR Doc. No. 8700-835-400-VIS, January 1998.
[5] "High Desert Power Project Ambient Air Quality Impact Assessment," ENSR Corp., ENSR Doc. No. 8700-835-400-AQIA, January 1998.
[6] "High Desert power Project NO_x Impact Assessment," ENSR Corp., ENSR Doc. No. 8700-835-400-NO_x, February 1998.

were later revised to reflect modifications to the proposed project.[7] The MDAQMD approves of the analysis methods used in these impact analyses and the findings of these impact analyses.

Findings

The impact analysis calculated a maximum HDPP incremental increase for each pollutant for each applicable averaging period. When added to the maximum recent background concentration, the HDPP did not exceed the most stringent (or lowest) standard for any pollutant, except those pollutants for which the background exceeds the standard. The HDPP was estimated to consume a maximum NO_2 increment of 0.01 $\mu g/m^3$ in a PSD Class I area, which is less than the NO_2 increment threshold of 2.5 $\mu g/m^3$. The HDPP was estimated to consume a maximum NO_2 increment of 8 $\mu g/m^3$ in a PSD Class II area, which is less than the overall NO_2 increment threshold of 25 $\mu g/m^3$.

	Project Impact	**Background**	**Total Impact**	**Federal Standard**	**State Standard**
Pollutant	*All values in $\mu g/m^3$*				
CO (1 hour)	7500	9200	16700	40000	23000
CO (8 hour)	900	8500	9400	10000	10000
PM_{10} (24 hour)	5	108	113	150	50
PM_{10} (annual)	3	42	45	50	30
SO_2 (3 hour)	4	35	39	1300	n/a
SO_2 (24 hour)	2	26	28	365	n/a
SO_2 (annual)	0	5	6	80	30
NO_2 (1 hour)	28	231	259	n/a	470
NO_2 (annual)	8	51	59	100	n/a

Inputs and Methods

Worst case emissions were used as inputs, meaning 100 percent full load or mixed full load and startup for averaging times longer than one hour, and uncontrolled startup conditions for one hour averaging times. Data from George AFB for 1987 through 1991 was used as the meteorological inputs. Maximum ambient concentration data for 1994 through 1997 from the Victorville site was used for background concentrations. Background ozone was converted to NO_2 (96 percent of ozone value) and added to measured NO_2 value to estimate background NO_2 value. The Ozone Limiting Method was used to estimate the 1-hour maximum NO_2 impact. For determining annual impacts, the conservative assumption of 100 percent conversion of NO_x to NO_2 was used.

The USEPA Industrial Source Complex Short Term Version 3 (ISCST3) dispersion model was used to estimate ambient concentrations resulting from HDPP emissions. The dispersion modeling was performed according to requirements stated in the Guideline on Air Quality Models (EPA-450/2-78-027R).

[7] "High Desert Power Project Revised Short-term Air Quality Impact Assessment," ENSR Corp., ENSR Doc. No. 8700-835-400-ST2, November 1998.

8. Health Risk Assessment

HDPP performed a Health Risk Assessment (HRA) for carcinogenic, non-carcinogenic chronic, and non-carcinogenic acute toxic air contaminants.[8] The MDAQMD approves of the analysis methods used in the HRA and the findings of the HRA.

Findings

The HRA calculated a peak 70-year cancer risk of 0.9 per million, located approximately 4 km east-northeast of the HDPP boundary. The calculated peak 70-year residential cancer risk is less than 1.0 per million (for all receptors). The maximum non-cancer chronic and acute Hazard Indices are both less than the significance level of 1.0 (0.1 and 0.8, respectively).

Inputs and Methods

The HDPP will emit toxic air contaminants as products of natural gas combustion, equipment wear, ammonia slip from the SCR systems, and cooling tower emissions. Combustion emissions were estimated using emission factors contained in the CARB California Air Toxics Emission Factors database. Toxic metal emissions (chromium, cobalt, nickel and manganese) were estimated by speciating fine particulate exhaust from natural gas combustion using CARB speciation factors (CARB, August 1991, Profile 123). Ammonia slip was assumed to be 10 ppm in the stack exhaust. Cooling tower emissions were estimated using USEPA emission factors for evaporative emissions and drift droplets (ammonia, chloroform and chlorine) and engineering calculation for droplets. Toxics in the cooling tower drift include: ammonia, chloroform, chlorine, phenols, sulfate, and the metals arsenic, beryllium, cadmium, copper, lead, mercury, nickel, selenium, and zinc.

The USEPA Industrial Source Complex Short Term Version 3 (ISCST3) dispersion model was used to estimate ambient concentrations of toxic air pollutants. The CAPCOA Assessment of Chemical Exposure for AB2588 Version 93288 (ACE2588) risk assessment model was used to estimate health risks due to exposure to emissions. Surface data from George AFB (1987 through 1991) and upper air data from Desert Rock, Nevada (1987 through 1991) were used as meteorological inputs.

9. Offset Requirements

MDAQMD Regulation XIII – *New Source Review* requires offsets for nonattainment pollutants and their precursors emitted by large, new sources. HDPP has prepared and submitted a proposed offset package for the proposed project as required by Rule 1302(C)(3)(b).[9] The HDPP is proposed for a location that has been designated nonattainment by USEPA for ozone and PM_{10}. MDAQMD Rule 1303(B)(1) specifies offset threshold amounts for the nonattainment pollutant PM_{10}. MDAQMD Rule 1303(B)(1) also specifies offset threshold amounts for precursors of

[8] "High Desert Power Project Health Risk Assessment," ENSR Corp., ENSR Doc. No. 8700-835-400-HRA, January 1998 and memorandum from H. Balentine (ENSR) to B. Zeller (MDAQMD) dated 4/13/98 (File 8700-835-300).

[9] "Offset Plan," HDPP LLC, March 19, 1998 and "High Desert Power Project Revised Offset Plan," ENSR Corp., ENSR Doc. No. 8700-835-400-ERC, November 1998.

nonattainment pollutants: NO_x (precursor of ozone and PM_{10}), SO_x (precursor of PM_{10}), and VOC (precursor of ozone and PM_{10}). A new facility which emits or has the potential to emit more than these offset thresholds must obtain offsets equal to the facility's entire potential to emit. As the following table shows, maximum HDPP annual emissions exceed the offset thresholds for three of the four nonattainment pollutants and/or precursors. The table uses HDPP maximum or worst-case annual emissions. The table also includes all applicable emissions, including the emissions increases from proposed new permit units (turbines, duct burners, SCR and wet cooling equipment), cargo carriers (none are proposed), fugitive emissions (none are proposed), and non-permitted equipment (none are proposed). For this analysis the MDAQMD assumes VOC is equivalent to ROC and SO_2 is equivalent to SO_x.

Comparison of HDPP Emissions with Offset Thresholds
All emissions in tons per year

	NO_x	**VOC**	**SO_x**	**PM_{10}**
Offset Threshold	25	25	25	15
Maximum HDPP Emissions	205	144	13	155
Configuration	3F	3F	3F	3F

Required Offsets

MDAQMD Rule 1305 increases the amount of offsets required based on the location of the facility obtaining the offsets (on a pollutant category specific basis). As the HDPP is located in two nonattainment areas, a federal ozone nonattainment area and a federal PM_{10} nonattainment area, the largest applicable offset ratio applies. The following table calculates the offsets required for the HDPP.

Emission Offsets Required for the HDPP
All emissions in tons per year

	NO_x	**VOC**	**SO_x**	**PM_{10}**
Maximum HDPP Emissions	205	144	13	155
Offset Ratio	1.3	1.3	1.0	1.0
Required Offsets	**267**	**187**	**13**	**155**

Identified Emission Reduction Credits

HDPP has identified several sources of emission reduction credits (ERCs). These sources are summarized below.

ERC Sources Identified by HDPP
All emissions in tons per year

Source	Location	**NO_x**	**VOC**	**SO_x**	**PM_{10}**
General Motors Corp. (Van Nuys)	SCAQMD – AQ002147		229		
Mobil Oil Corp. (Torrance)	SCAQMD – AQ002293		73		
Chemoil Refining (Carson)	SCAQMD – AQ002387		43		
Crown Cork & Seal (Los Angeles)	SCAQMD – AQ000771/2		118		
BASF Corp. (Orange County)	SCAQMD – AQ001724		40		

Southern California International Airport Authority (Victorville)	MDAQMD - 0007	134	151	3	14
City of Adelanto	MDAQMD				168
	Total ERCs Identified:	**134**	**654**	**3**	**182**

Inter-District, Inter-Basin and Inter-Pollutant Offsetting

HDPP has proposed the use inter-district, inter-air basin and inter-pollutant ERC trading to make up for the limited amount of NO_x ERCs available within the MDAQMD. HDPP has proposed the use of inter-pollutant ERC trading to make up for the limited amount of SO_x ERCs available within the MDAQMD. The use of inter-district, inter-air basin and inter-pollutant offsets is specifically allowed for by Rule 1305(B)(4) through (6) (in consultation with CARB and USEPA, and in the case of inter-pollutant offsets, with the approval of USEPA).

As SO_x is a PM_{10} precursor, SO_x and/or PM_{10} offsets can be used to offset SO_x emissions.

HDPP is proposing to use VOCs from the South Coast Air Basin within the jurisdiction of SCAQMD in place of NO_x at a one to one ratio. HDPP justifies this ratio by determining the ratio of reductions (across the entire region that includes Victorville) required to bring the Victorville area into attainment of the ozone NAAQS. This determination was done using the version of the SCAQMD urban airshed model that was used to develop the SCAQMD 1997 Air Quality Management Plan (AQMP). The analysis examined the modeling episode with the highest ozone concentrations at Victorville (September 7-9).

The first step in this analysis required the creation of an ambient ozone concentration isopleth diagram for the Victorville grid cell by varying VOC and NO_x reductions during the baseline year (1987). The second step required establishing Victorville ambient concentrations during the attainment year (2007) by: (1) plotting points representing year 2007 baseline and control case emission reductions from the SCAQMD 1997 AQMP on the isopleth diagram; and (2) extending a trajectory line from the original conditions (no reductions), through the year 2007 baseline point, through the year 2007 control case point (sufficient reductions to bring the applicable region into attainment of the ozone NAAQS), and through the attainment or ozone NAAQS (12 pphm) isopleth. This trajectory line effectively describes how the ambient concentrations at Victorville will change over time (within the constraints of the 1987 emissions inventory for the September 7-9 modeling episode). The point at which this line intersects the 12 pphm isopleth identifies the regional emission reductions required to bring ambient concentrations at Victorville down to 12 pphm.

The emissions management strategy for the region involves moving to the left and downward along this trajectory line. The concept of emissions trading is to avoid backtracking along the line or increasing the ambient ozone concentration when NO_x emissions are increased locally. To do this requires that the VOC emissions be decreased by enough to have the endpoint of the trading trajectory either on the same isopleth as before the trade, or on an isopleth representing a lower ozone concentration. As the emissions management strategy for the region positions the Victorville grid cell above the knee on the attainment isopleth, any trading trajectory that has an

endpoint above or to the left is acceptable. A VOC to NO_x trading ratio of 1 to 1 represents a trajectory that is approximately perpendicular to (above) the attainment trajectory whose endpoint is on an isopleth below 12 pphm. Thus a VOC to NO_x emissions offset ratio of 1 to 1 is a conservative requirement.

This analysis uses the best available tool for the exploration of ozone concentrations (the urban airshed model). This analysis examines the entire region, including all identified sources of ERCs. This analysis is performed within the framework of the region's attainment plan. The District therefore determines that the inter-district, inter-basin, and inter-pollutant trade is technically justified and will not cause or contribute to a violation of an ambient air quality standard. The District concludes that a VOC to NO_x ratio of one to one is acceptable for the VOC ERCs originating within the South Coast Air Basin for the HDPP and is beneficial to both air districts. The District also concludes that a PM_{10} to SO_x ratio of one to one is acceptable for PM_{10} ERCs originating within the MDAQMD.

10. Applicable Regulations and Compliance Analysis

Selected MDAQMD Rules and Regulations will apply to the proposed project.

Regulation II – Permits

Rule 221 – *Federal Operating Permit Requirement* requires certain facilities to obtain Federal Operating Permits. The proposed project will be required to submit an application for a federal operating permit within twelve months of the commencement of operations.

Regulation IV - Prohibitions

Rule 401 – *Visible Emissions* limits visible emissions opacity to less than 20 percent (or Ringlemann No. 1). During start up, visible emissions may exceed 20 percent opacity. However, emissions of this opacity are not expected to last three minutes or longer. In normal operating mode, visible emissions are not expected to exceed 20 percent opacity.

Rule 402 – *Nuisance* prohibits facility emissions that cause a public nuisance. The proposed turbine power train exhaust is not expected to generate a public nuisance due to the sole use of pipeline-quality natural gas as a fuel. In addition, due to the location of the proposed project, no nuisance complaints are expected.

Rule 403 – *Fugitive Dust* specifies requirements for controlling fugitive dust. The proposed project does not include any significant sources of fugitive dust so the proposed project is not expected to violate Rule 403.

Rule 403.2 – *Fugitive Dust Control for the Mojave Desert Planning Area* specifies requirements for construction projects. The construction of the proposed project will be required to comply with the requirements of Rule 403.2.

Rule 404 – *Particulate Matter – Concentration* specifies standards of emissions for particulate matter concentrations. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 404.

Rule 405 – *Solid Particulate Matter - Weight* limits particulate matter emissions from fuel combustion on a mass per unit combusted basis. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 405.

Rule 406 – *Specific Contaminants* limits sulfur dioxide emissions. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 406.

Rule 408 – *Circumvention* prohibits hidden or secondary rule violations. The proposed project is not expected to violate Rule 408.

Rule 409 – *Combustion Contaminants* limits total particulate emissions on a density basis. The sole use of pipeline-quality natural gas a fuel will keep proposed project emission levels in compliance with Rule 409.

Rule 430 – *Breakdown Provisions* requires the reporting of breakdowns and excess emissions. The proposed project will be required to comply with Rule 430 by permit condition.

Rule 431 – *Sulfur Content in Fuels* limits sulfur content in gaseous, liquid and solid fuels. The sole use of pipeline-quality natural gas a fuel will keep the proposed project in compliance with Rule 431.

Rule 475 – *Electric Power Generating Equipment* limits NO_x and particulate matter emissions with mass rate and concentration standards. Permit conditions for the proposed project will establish limits which are in compliance with Rule 475.

Regulation IX – Standards of Performance for New Stationary Sources

Regulation IX includes by reference the New Source Performance Standard (NSPS) for gas turbines (40 CFR 60 Subpart GG, §§60.330 through 60.334). Permit conditions for the proposed project will establish limits which are in compliance with the gas turbine NSPS referenced in Regulation IX.

Regulation XII – Federal Operating Permits

Regulation XII contains requirements for sources which must have a federal operating permit and an acid rain permit. The proposed project will be required to submit applications for a federal operating permit and an acid rain permit by the appropriate date.

Regulation XIII – New Source Review

Rule 1300 – *General* ensures that Prevention of Significant Deterioration (PSD) requirements apply to all projects. The proposed project has submitted an application to the USEPA for an NO_2 and CO PSD permit, complying with Rule 1300.

Rule 1302 – *Procedure* requires certification of compliance with the Federal Clean Air Act, applicable implementation plans, and all applicable MDAQMD rules and regulations. The ATC application package for the proposed project includes sufficient documentation to comply with Rule 1302(D)(5)(b)(iii). Permit conditions for the proposed project will require compliance with Rule 1302(D)(5)(b)(iv).

Rule 1303 – *Requirements* requires BACT and offsets for selected large new sources. Permit conditions will limit the emissions from the proposed project to a level which has been defined as BACT for the proposed project, bringing the proposed project into compliance with Rule 1302(A). Prior to the commencement of construction the proposed project shall have obtained sufficient offsets to comply with Rule 1303(B)(1).

Rule 1306 – *Electric Energy Generating Facilities* places additional administrative requirements on projects involving approval by the California Energy Commission (CEC). The proposed project will not receive an ATC without CEC's approval of their Application for Certification, ensuring compliance with Rule 1306.

Maximum Achievable Control Technology Standards

Health & Safety Code §39658(b)(1) states that when USEPA adopts a standard for a toxic air contaminant pursuant to §112 of the Federal Clean Air Act (42 USC §7412), such standard becomes the Airborne Toxic Control Measure (ATCM) for the toxic air contaminant. Once an ATCM has been adopted it becomes enforceable by the MDAQMD 120 days after adoption or implementation (Health & Safety Code §39666(d)). USEPA has not to date adopted a Maximum Achievable Control Technology (MACT) standard that is applicable to the proposed project. Should USEPA adopt an applicable MACT in the future, the MDAQMD will be required to enforce said MACT as an ATCM on the proposed project.

11. Conclusion

The MDAQMD has reviewed the proposed project's Application for New Source Review. The MDAQMD has determined that the proposed project, after application of the permit conditions (including BACT requirements) given below, will comply with all applicable MDAQMD Rules and Regulations. This PDOC will be released for public comment and publicly noticed on or about December 16. Written comments will be accepted for thirty days from the date of publication of the public notice. A Final Determination of Compliance shall be prepared no later than thirty days after the public comment period (on or about February 19, 1999).

12. Permit Conditions

The following permit conditions will be placed on the Authorities to Construct for the proposed project. Separate permits will be required for each turbine power train, irrespective of final configuration. Separate permits will also be required for each SCR system, oxidation catalyst, duct burner and cooling tower.

3F Configuration Turbine Power Train Authority to Construct Conditions

[3 individual 1711 MMBtu/hr F Class Gas Turbine Generators,
Application Numbers: 98001134, 98001138 and 98001142]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be exclusively fueled with natural gas, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. This equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and GG (Standards of Performance for Stationary Gas Turbines). This equipment is also subject to the Federal Acid Rain Program – Title IV. Compliance with all applicable provisions of these regulations is required.

4. Emissions from the entire facility shall not be exceed the following emission limits at any firing rate, except for CO and NO_x during periods of startup and shutdown:
   a. Hourly rates, based on a three-hour rolling average, computed every 15 minutes, verified by CEMS and annual compliance tests:
      i. NO_x as NO_2 – 54.3 lb/hr (based on 2.5 ppmvd corrected to 15% O_2)
      ii. CO – 105.3 lb/hr (based on 8.0 ppmvd corrected to 15% O_2)
   b. Hourly rates, verified by annual compliance tests:
      i. VOC as CH_4 – 13.5 lb/hr (based on 4 ppmvd corrected to 15% O_2)
      ii. SO_x as SO_2 – 3.6 lb/hr (based on 0.00064 lb/MMBtu (lower heating value))
      iii. PM_{10} – 35.4 lb/hr (based on 0.0074 lb/MMBtu (lower heating value))

5. Emissions of CO and NO_x from this equipment may exceed the limits contained in Condition 4 during startup and shutdown periods as follows:
   a. Startup shall be defined as the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits. Cold startup means a startup when the CTG has not been in operation for more than 72 hours. Hot startup means a startup when the CTG has not been in operation for 8 hours or less. Warm startup means a startup that is not a hot or cold startup. Shutdown shall be defined as the period beginning with the lowering of equipment from base load and lasting until fuel flow is completely off and combustion has ceased.
   b. During a cold startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 183 lb
      ii. CO – 3541 lb
   c. During a warm startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 168 lb
      ii. CO – 3596 lb
   d. During a hot startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 138 lb
      ii. CO – 3729 lb

e. During a shutdown emissions shall not exceed the following, verified by CEMS:
   i. NO_x – 97 lb
   ii. CO – 239 lb

6. Emissions from the entire facility may not exceed the following emission limits including emissions allowed by Condition 5, irrespective of operational mode:
   a. Daily rates, based on a calendar day summary and verified by CEMS or annual compliance tests (or other compliance methods in the case of SO_x):
      i. NO_x – 2543 lb/day
      ii. CO – 25200 lb/day
      iii. SO_x as SO_2 – 80 lb/day
      iv. PM_{10} – 850 lb/day
   b. Annual rates, based on a rolling 52 week summary and verified by CEMS or annual compliance tests (or other compliance methods in the case of SO_x):
      i. NO_x – 205 tons/year
      ii. CO – 914 tons/year
      iii. VOC as CH_4 – 144 tons/year
      iv. SO_x as SO_2 – 13 tons/year
      v. PM_{10} – 155 tons/year

7. The number, date and durations of start-ups, shutdowns and breakdowns shall be recorded.

8. The operator shall not operate this equipment without the selective catalytic NO_x reduction (insert Permit No. here) and VOC and CO oxidation catalyst (insert Permit No. here) systems installed and fully functional.

9. Emissions of NO_x, CO, and O_2 shall be monitored using a Continuous Emissions Monitoring System (CEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using a Continuous Emission Rate Monitoring System (CERMS). The operator shall, install, calibrate, maintain, and operate these monitoring systems according to an MDAQMD-approved monitoring plan and MDAQMD Rule 218, and shall be installed prior to initial equipment startup. Six (6) months prior to installation the operator shall submit a monitoring plan for MDAQMD review and approval.

10. The operator shall conduct all required compliance/certification tests in accordance with an MDAQMD-approved test plan. Thirty (30) days prior to the compliance/certification tests the operator shall provide a written test plan for MDAQMD review and approval. Written notice of the compliance/certification test shall be provided to the MDAQMD ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the MDAQMD within forty-five (45) days after testing.

11. The operator shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the

MDAQMD no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:

a. NO_x as NO_2 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 19 and 20).
b. VOC as CH_4 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 25A and 18).
c. SO_x as SO_2 in ppmvd at 15% O_2 and lb/hr (quarterly average natural gas sulfur content reports from the natural gas supplier(s) in containing a guaranteed maximum sulfur content (or laboratory analysis), or a custom fuel monitoring schedule approved by USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG are acceptable alternatives).
d. CO in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Method 10).
e. PM_{10} in mg/m^3 at 15% O_2 and lb/hr (as front half PM measured per USEPA Reference Method 5).
f. Flue gas flow rate in scfmd.

12. Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B:
    a. For NO_x, Performance Specification 2.
    b. For O_2, Performance Specification 3.
    c. For CO, Performance Specification 4.
    d. For stack gas flow rate, Performance Specification 6.

13. The operator shall maintain and submit to the APCO the information required by an MDAQMD-approved monitoring and reporting plan. The operator shall obtain an MDAQMD-approved monitoring and reporting plan not later than the date of first start-up.

14. The owner/operator must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 267 tons of NO_x, 187 tons of VOC, 13 tons of SO_x, and 155 tons of PM_{10} offsets (or the equivalent).

15. During an initial commissioning period of no more than 120 days, commencing with the first firing of fuel in this equipment, NO_x, CO, VOC and ammonia concentration limits shall not apply.

16. Within 60 days after achieving the maximum firing rate at which the facility will be operated, but not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the following limits.
    a. Emission limits in Condition 4 and
    b. Ammonia slip.

17. The initial compliance test shall include tests for the following. The results of the initial compliance test shall be used to prepare a supplemental health risk analysis.
    a. Aldehydes and acrolein (measured per CARB method 430);
    b. Certification of CEMS and CERMS at 100% load;
    c. Characterization of cold startup VOC emissions;
    d. Characterization of warm startup VOC emissions; and
    e. Characterization of hot startup VOC emissions.

3F Configuration Duct Burner Authority to Construct Conditions

[3 individual 150 MMBtu/hr Natural Gas Duct Burners,
Application Numbers: 98001135, 98001139 and 98001143]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be exclusively fueled with natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. The duct burner shall not be operated unless the associated (insert permit No. here) turbine power train is in operation.

4. Fuel use by this equipment shall be recorded and maintained on site for a minimum of two (2) years and shall be provided to MDAQMD personnel on request.

3F Configuration Selective Catalytic NO_x Reduction System Authority to Construct Conditions

[3 individual SCR systems, Application Numbers: 98001136, 98001140 and 98001144]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. This equipment shall be operated concurrently with the gas turbine covered in valid MDAQMD permit (insert Permit No. here).

4. Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded the manufacturer's minimum recommended operating temperature except for periods of equipment malfunction. Except during periods of startup and shutdown, ammonia slip shall not exceed 10 ppm volume dry at 15 percent O_2, averaged over every three hours.

5. Ammonia injection by this equipment in pounds per hour shall be recorded and maintained on site for a minimum of two (2) years and shall be provided to MDAQMD personnel on request.

3F Configuration VOC and CO Oxidation Catalyst Authority to Construct Conditions

[3 individual High Temperature Oxidation Catalysts,
Application Numbers: 99003920, 99003921 and 99003922]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3F Configuration Cooling Tower Authority to Construct Conditions

[3 individual Cooling Towers, Application Numbers: 98001137, 98001141 and 98001145]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. The drift rate shall not exceed 0.001 percent with a maximum circulation rate of 57,300 gallons per minute. The maximum hourly PM_{10} emission rate shall not exceed 1.1 pounds per hour.

4. The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log which contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of two (2) years and shall be provided to MDAQMD personnel on request.

5. The operator shall conduct all required cooling tower water quality tests in accordance with an MDAQMD-approved test protocol. Thirty (30) days prior to the first such test the operator shall provide a written test protocol for MDAQMD review and approval.

6. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and be available to MDAQMD personnel on request.

2G Configuration Turbine Power Train Authority to Construct Conditions

[2 individual 2230 MMBtu/hr G Class Gas Turbine Generators,
Application Numbers: 98001146 and 98001150]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be exclusively fueled with natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. This equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and GG (Standards of Performance for Stationary Gas Turbines). This equipment is also subject to the Federal Acid Rain Program – Title IV. Compliance with all applicable provisions of these regulations is required.

4. Emissions from the entire facility shall not be exceed the following emission limits at any firing rate, except for CO and NO_x during periods of startup and shutdown:
   a. Hourly rates, based on a three-hour rolling average, computed every 15 minutes, verified by CEMS and annual compliance tests:
      i. NO_x as NO_2 – 49.2 lb/hr (based on 2.5 ppmvd corrected to 15% O_2)
      ii. CO – 95.8 lb/hr (based on 8.0 ppmvd corrected to 15% O_2)
   b. Hourly rates, based on a calendar day average, verified by annual compliance tests:
      i. VOC as CH_4 – 13 lb/hr (based on 4 ppmvd corrected to 15% O_2)
      ii. SO_x as SO_2 – 3.2 lb/hr (based on 0.00064 lb/MMBtu (lower heating value))
      iii. PM_{10} – 23.2 lb/hr (based on 0.0054 lb/MMBtu (lower heating value))

5. Emissions of CO and NO_x from this equipment may exceed the limits contained in Condition 4 during startup and shutdown periods as follows:
   a. Startup shall be defined as the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits. Cold startup means a startup when the CTG has not been in operation for more than 72 hours. Hot startup means a startup when the CTG has not been in operation for 8 hours or less. Warm startup means a startup that is not a hot or cold startup. Shutdown shall be defined as the period beginning with the lowering of equipment from base load and lasting until fuel flow is completely off and combustion has ceased.
   b. During a cold startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 561 lb
      ii. CO – 6890 lb
   c. During a warm startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 269 lb
      ii. CO – 3177 lb
   d. During a hot startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 215 lb
      ii. CO – 2711 lb

e. During a shutdown emissions shall not exceed the following, verified by CEMS:
   i. NO_x – 133 lb
   ii. CO – 288 lb

6. Emissions from the entire facility may not exceed the following emission limits including emissions allowed by Condition 5, irrespective of operational mode:
   a. Daily rates, based on a calendar day summary and verified by CEMS or annual compliance tests (or other compliance method in the case of SO_x):
      i. NO_x – 2921 lb/day
      ii. CO – 22000 lb/day
      iii. SO_x as SO_2 – 72 lb/day
      iv. PM_{10} – 554 lb/day
   b. Annual rates, based on a rolling 52 week summary and verified by CEMS or annual compliance tests (or other compliance method in the case of SO_x):
      i. NO_x – 189 tons/year
      ii. CO – 631 tons/year
      iii. VOC as CH_4 – 103 tons/year
      iv. SO_x as SO_2 – 13 tons/year
      v. PM_{10} – 104 tons/year

7. The number, date and durations of start-ups, shutdowns and breakdowns shall be recorded.

8. The operator shall not operate this equipment without the selective catalytic NO_x reduction (insert Permit No. here) and VOC and CO oxidation catalyst (insert Permit No. here) systems installed and fully functional.

9. Emissions of NO_x, CO, and O_2 shall be monitored using a Continuous Emissions Monitoring System (CEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using a Continuous Emission Rate Monitoring System (CERMS). The operator shall, install, calibrate, maintain, and operate these monitoring systems according to an MDAQMD-approved monitoring plan and MDAQMD Rule 218, and shall be installed prior to initial equipment startup. Six (6) months prior to installation the operator shall submit a monitoring plan for MDAQMD review and approval.

10. The operator shall conduct all required compliance/certification tests in accordance with an MDAQMD-approved test plan. Thirty (30) days prior to the compliance/certification tests the operator shall provide a written test plan for MDAQMD review and approval. Written notice of the compliance/certification test shall be provided to the MDAQMD ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the MDAQMD within forty-five (45) days after testing.

11. The operator shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the

MDAQMD no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:

a. NO_x as NO_2 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 19 and 20).
b. VOC as CH_4 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 25A and 18).
c. SO_x as SO_2 in ppmvd at 15% O_2 and lb/hr (quarterly average natural gas sulfur content reports from the natural gas supplier(s) in containing a guaranteed maximum sulfur content (or laboratory analysis), or a custom fuel monitoring schedule approved by USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG are acceptable alternatives).
d. CO in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Method 10).
e. PM_{10} in mg/m^3 at 15% O_2 and lb/hr (as front half PM measured per USEPA Reference Method 5).
f. Flue gas flow rate in scfmd.

12. Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B:
    a. For NO_x, Performance Specification 2.
    b. For O_2, Performance Specification 3.
    c. For CO, Performance Specification 4.
    d. For stack gas flow rate, Performance Specification 6.

13. The operator shall maintain and submit to the APCO the information required by an MDAQMD-approved monitoring and reporting plan. The operator shall obtain an MDAQMD-approved monitoring and reporting plan not later than the date of first start-up.

14. The owner/operator must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 246 tons of NO_x, 134 tons of VOC, 13 tons of SO_x, and 104 tons of PM_{10} offsets (or the equivalent).

15. During an initial commissioning period of no more than 120 days, commencing with the first firing of fuel in this equipment, NO_x, CO, VOC and ammonia concentration limits shall not apply.

16. Within 60 days after achieving the maximum firing rate at which the facility will be operated, but not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the following limits.
    a. Emission limits in Condition 4 and
    b. Ammonia slip.

17. The initial compliance test shall include tests for the following. The results of the initial compliance test shall be used to prepare a supplemental health risk analysis.
    a. Aldehydes and acrolein (measured per CARB method 430);
    b. Certification of CEMS and CERMS at 100% load;
    c. Characterization of cold startup VOC emissions;
    d. Characterization of warm startup VOC emissions; and
    e. Characterization of hot startup VOC emissions.

2G Configuration Duct Burner Authority to Construct Conditions

[2 individual 165 MMBtu/hr Natural Gas Duct Burners,
Application Numbers: 98001147 and 98001151]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be exclusively fueled with natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. The duct burner shall not be operated unless the associated (insert permit No. here) turbine power train is in operation.

4. Fuel use by this equipment shall be recorded and maintained on site for a minimum of two (2) years and shall be provided to MDAQMD personnel on request.

2G Configuration Selective Catalytic NO_x Reduction System Authority to Construct Conditions

[2 individual SCR systems, Application Numbers: 98001148 and 98001152]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. This equipment shall be operated concurrently with the gas turbine covered in valid MDAQMD permit (insert Permit No. here).

4. Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded the manufacturer's minimum recommended operating temperature except for periods of equipment malfunction. Except during periods of startup and shutdown, ammonia slip shall not exceed 10 ppm volume dry at 15 percent O_2, averaged over every three hours.

5. Ammonia injection by this equipment in pounds per hour shall be recorded and maintained on site for a minimum of two (2) years and shall be provided to MDAQMD personnel on request.

2G Configuration VOC and CO Oxidation Catalyst Authority to Construct Conditions

[2 individual High Temperature Oxidation Catalysts
Application Numbers: 99003923 and 99003924]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

2G Configuration Cooling Tower Authority to Construct Conditions

[2 individual Cooling Towers, Application Numbers: 98001149 and 98001153]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. The drift rate shall not exceed 0.001 percent with a maximum circulation rate of 73,540 gallons per minute. The maximum hourly PM_{10} emission rate shall not exceed 1.5 pounds per hour.

4. The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log which contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of two (2) years and shall be provided to MDAQMD personnel on request.

5. The operator shall conduct all required cooling tower water quality tests in accordance with an MDAQMD-approved test protocol. Thirty (30) days prior to the first such test the operator shall provide a written test protocol for MDAQMD review and approval.

6. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure is to be kept on-site and be available to MDAQMD personnel on request.

13. Agency Notification

Any comments on this Preliminary Determination of Compliance shall be forwarded to:

Charles L. Fryxell, Air Pollution Control Officer
Mojave Desert Air Quality Management District
15428 Civic Drive, Suite 200
Victorville, CA 92392-2383

All correspondence as required by Rule 1306 shall be forwarded to:

David Howekamp, Director
Office of Air Division
Matt Haber, Chief
Permits Office
United States EPA, Region IX
75 Hawthorne Street
San Francisco, CA 94105

Peter Venturini, Chief
Stationary Source Division
Dean Saito, District Liaison
Executive Office
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Richard Buell, Siting Project Manager
Energy Facilities Siting Division
California Energy Commission
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